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An Advanced Fracture Characterization and Well Path Navigation System for Effective Re-Development and Enhancement of Ultimate Recovery from the Complex Monterey Reservoir of South Ellwood Field, Offshore California

Quarterly Technical Progress Report

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Progress Report January 1 - March 31, 2001

Disclaimer

Abstract

Venoco Inc, intends to re-develop the Monterey Formation, a Class III basin reservoir, at South Ellwood Field, Offshore Santa Barbara, California.

Well productivity in this field varies significantly. Cumulative Monterey production for individual wells has ranged from 260 STB to 8,700,000 STB. Productivity is primarily affected by how well the well path connects with the local fracture system and the degree of aquifer support. Cumulative oil recovery to date is a small percentage of the original oil in place. To embark upon successful re-development and to optimize reservoir management, Venoco intends to investigate, map and characterize field fracture patterns and the reservoir conduit system. State of the art borehole imaging technologies including FMI, dipole sonic and cross-well seismic, interference tests and production logs will be employed to characterize fractures and micro faults. These data along with the existing database will be used for construction of a novel geologic model of the fracture network. Development of an innovative fracture network reservoir simulator is proposed to monitor and manage the aquifer's role in pressure maintenance and water production. The new fracture simulation model will be used for both planning optimal paths for new wells and improving ultimate recovery.

In the second phase of this project, the model will be used for the design of a pilot program for downhole water re-injection into the aquifer simultaneously with oil production. Downhole water separation units attached to electric submersible pumps will be used to minimize surface fluid handling thereby improving recoveries per well and field economics while maintaining aquifer support.

In cooperation with the DOE, results of the field studies as well as the new models developed and the fracture database will be shared with other operators. Numerous fields producing from the Monterey and analogous fractured reservoirs both onshore and offshore will benefit from the methodologies developed in this project.

This report presents a summary of all technical work conducted during the third quarter of Budget Period I.

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Introduction

The Field Demonstration site for this Class III (basin clastic) Program Proposal is the South Ellwood Field located offshore California. The Monterey Formation is the main producing unit in the South Ellwood Field and consists of fractured chert, porcelanite, dolomite, and siliceous limestone interbedded with organic mudstone. This reservoir has an average thickness of 1,000 feet, and lies at subsea depths of approximately -3,500’ to -5,000’.

Venoco and USC jointly submitted an application to conduct a DOE co-operative investigation of the Monterey formation at South Ellwood in June 2000. The DOE granted this application in July 2000.

Executive Summary

Venoco and USC prepared a proposal for a DOE sponsored joint investigation of the fractured Monterey formation. It was agreed that Venoco would construct the geologic model for the field and gather new reservoir data as appropriate. USC would then develop a simulation model that would be used to optimize future hydrocarbon recovery. Joint Venoco-USC teams were established to manage the flow of data and insure that Venoco and USC activities remained synchronized. A co-operative agreement was signed with the DOE on July 31, 2000.

Data acquisition activities featured prominently during the Third quarter. State of the art production logs (DEFT and GHOST) were run on five South Ellwood wells to identify oil, gas and water producing perforations. Zones in three wells were identified for water shut-off. These workovers will take place in early 2002.

The pattern recognition technique for identifying fractures from older well logs was completed. A strong correlation was established between the wells with greatest number of log derived fracture events and those with the highest cumulative fluid production. Several wells were identified with overlooked potentially productive zones. These wells will be targeted for additional perforations in 2002. The results of this work were presented a regional SPE meeting in Bakersfield.

It became evident that, due to great variety of data being stored in the South Ellwood public access database, the CD-ROM format was no longer suitable. The database was migrated to an HTML Intranet format.

Task I-Database

Two platforms for the South Ellwood database were considered, a CD-ROM version and a web-based intranet system. The CD-ROM version is an access database. The access database was designed and populated first. A design map of this version is shown in Figure 1. The limitations of Microsoft Access were felt when dealing with a wide variety of data in different formats. Due to these limitations the Access version of the database is in three different databases. The CD-ROM version of the database is in its final stages. The main CD will contain all of the raw data and the diagnostic data through this date. The remaining two CD's contain the core photos for 3242-19 and a detailed fracture study on those core photos.

The web-based intranet version of the database is the new dynamic version of the South Ellwood Database. This version contains all data that is in the CD-ROM version plus new diagnostic data. A site map of this new design is shown Figure 2. Aside from continued population and design a few key design aspects are being created and applied. First is a search engine for the whole database web site. This will enable a first time user to type in any type of data and all the pages containing that data will be given. The second design aspect is application of real time the production diagnostic plots. This will have the diagnostic plots generated directly from the production data and thus as the production data is updated the diagnostics will reflect that change immediately.

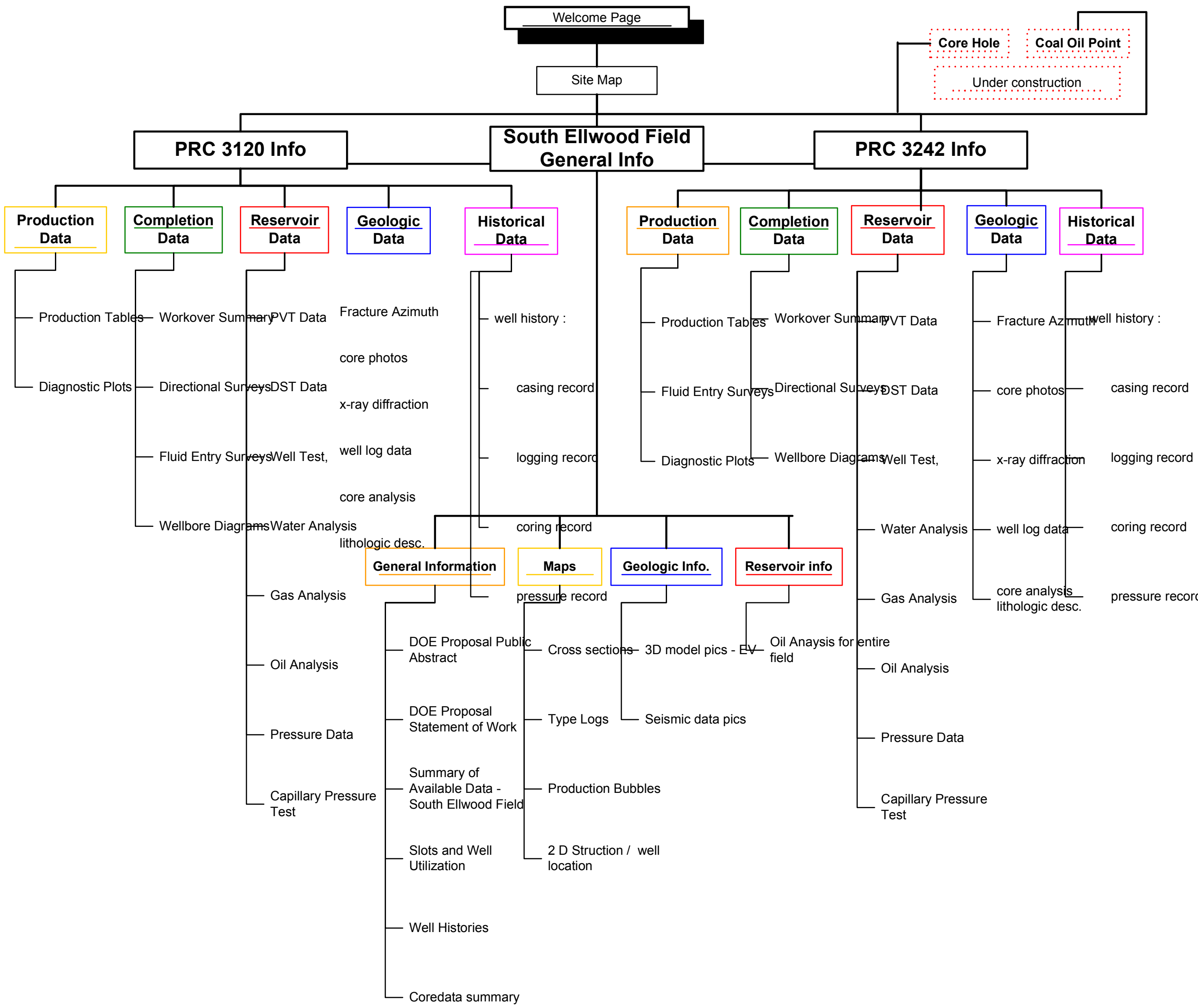

Figure 1- site map for the CD-ROM version of the South Ellwood database.

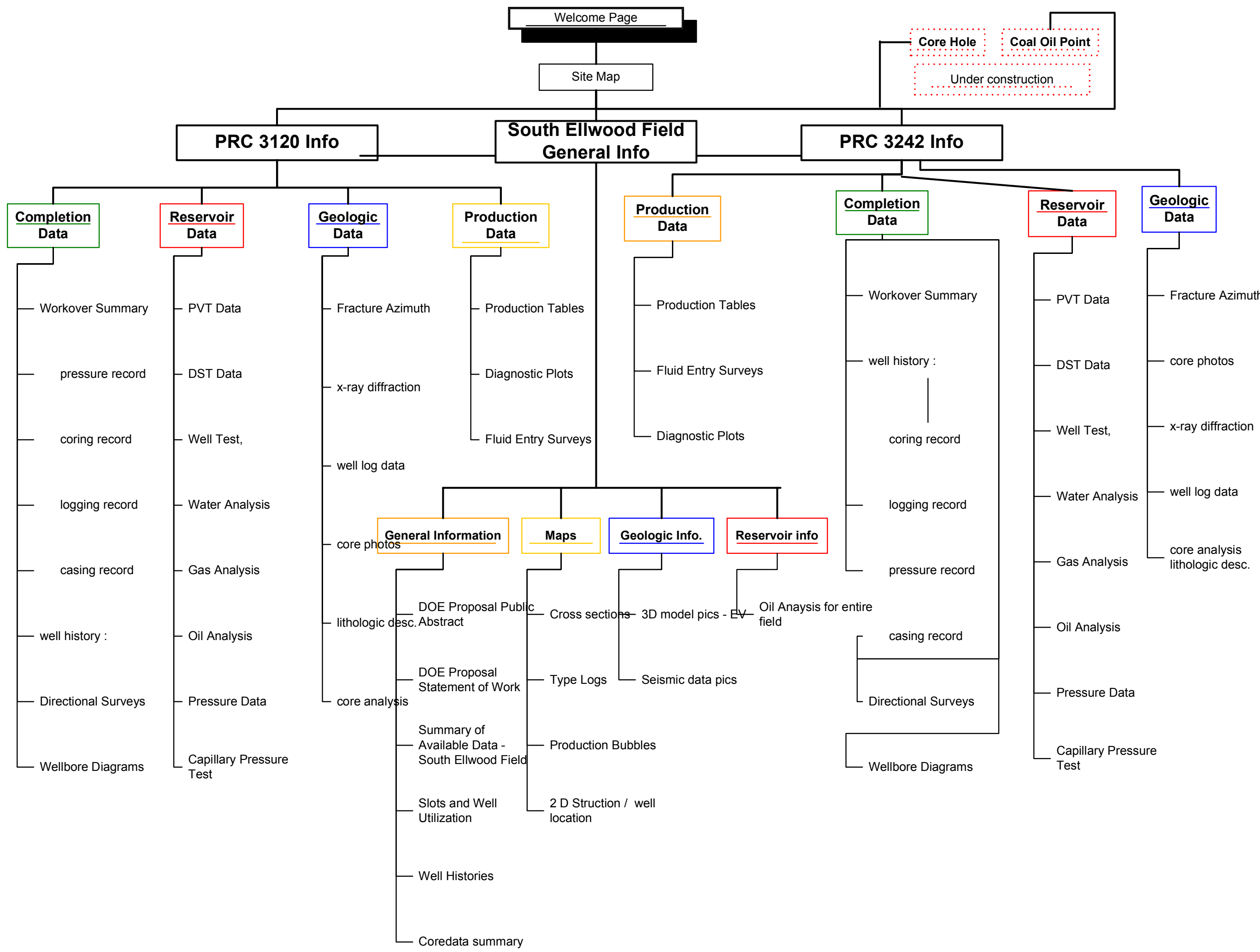

Figure 2 - Site map for the Intra-net version of the South Ellwood database

Task II-New Data

We attempted state of the art production logs (GHOST and DEFT tools) on 6 wells. The DEFT tool is an electrical imaging device that distinguishes between water and hydrocarbons. The GHOST tool is an optical imaging device that distinguishes between gas and oil. Five of these production logging runs were successfully completed, identifying 3 clear water shut offs.

The production logs from 3120-9 and 3242-12 indicate a good possibility to shut off bottom water. Venoco plans to run a through tubing bridge plug in these wells in 2002. The log in 3242-18 shows that 90% of the produced water is coming from the open hole section of the Monterey M6. A workover to isolate this zone will take place in January 2002. 3120-16 has no clear water shut-off possibilities. Operational constraints prevented obtaining a log on the remaining two wells - 3242-9 and 3120-12. If the results of the new workovers are successful, we will have verified an excellent means of quantifying complex fluid flow in the Monterey fracture systems

Task III: Geological/Reservoir

Basic Reservoir Studies

Dipmeter reprocessing/analysis was conducted on all available dipmeter logs in the field. Schlumberger recovered archived data for dipmeters from 11 highly deviated wells. No more preserved digital data appears to exist as the remaining wells were drilled prior to 1970. We also calibrated digital data using original field prints. We reviewed methodology for presenting borehole breakouts and fracture picks. An analysis of regional data suggests that the maximum stress direction for the South Ellwood field is North-South. Borehole breakouts should be observable and oriented East-West.

Pipeline Model Development

During this quarter, major progress has been made in the following aspects:

- Completely revised the pipe network model: from using hydraulic equation in pipes to using Darcy's law (see below).
- Proposed and derived a semi-implicit finite difference algorithm for the above permeable pipe network model.
- Designed and coded the 2-D pipe network model (PNM).

The new pipe network model is suitable for three-dimensional three-phase flows. Its extension to three-dimensional three-phase flow is straightforward. Fig. 3 shows the schematics of the conceptual model proposed. Formulation of the 3-D algorithm is underway.

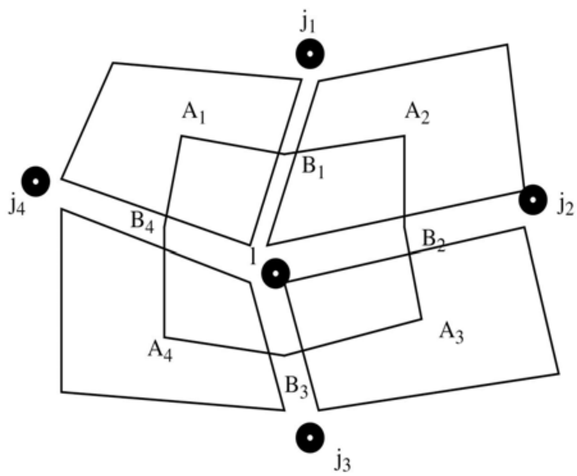

Figure 3. The schematics of the pipe network model.

Permeable pipes connect each other to form a network that represents fluid flow channel. In **Fig. 3**, we illustrate an inner junction connecting 4 pipes in the network. It is not a mandatory to use 4 pipes (rectangular or quadrilateral block blocks) to connect an inner network junction. The number of the pipes connecting a junction is arbitrary, and the directions of those pipes are also without constrains (unless they are in the same plane for 2D problems). This flexibility enables the new model to represent particular major fractures better. The micro-fractures and/or matrix around a junction form a storage block. $A_1B_1A_2B_2A_3B_3A_4B_4$ constitute the boundaries of the block around junction "l". Here A_1, A_2, A_3 and A_4 are weight centers of polygons around junction "l", and B_1, B_2, B_3 and B_4 are the middle positions along each pipes connecting "l" respectively.

The mass balance at junction "l" can be written as

$$\sum_{j=1}^{M_l} Q_{\alpha l,j} + E_{\alpha l} + N_{\alpha l} = \frac{V_l}{5.615}\frac{\partial}{\partial t}\left(\frac{\phi_p S_{\alpha p}}{B_{\alpha p}}\right) \tag{1}$$

Where α=o or w, $Q_{\alpha l,j}$ is phase α flow from the junction "j" to the junction "l", M_l is number of pipes connecting the junction "l", $E_{\alpha l}$ is the matrix transfer flow rate of phase α, $N_{\alpha l}$ is the production or injection of phase α, V_l is the block volume, ϕ_p is effective pipe porosity fraction in that block, $S_{\alpha p}$ represents pipe network saturation of phase α, and B_α is the phase α formation volume factor.
Now we will obtain the first two terms in Eq. (1). We apply Darcy's law for the fluid flow from junction to junction. The first term in Eq. (1) is

$$Q_{\alpha l,j} = -\frac{\beta A_{l,j} K_{pl,j} k_{r\alpha p}}{\mu_\alpha B_\alpha}\left(\frac{\partial p_{\alpha p}}{\partial s} - \gamma_\alpha \frac{\partial Z}{\partial s}\right)_{l,j} \tag{2}$$

where β is unit constant, $A_{l,j}$ is pipe cross section area between junction "l" and "j", $K_{\alpha l,j}$ is absolute permeability value of the pipe connecting "l" and "j", $k_{r\alpha p}$ is the relative permeability of phase α in pipes, μ_α is the phase α viscosity, $p_{\alpha p}$ is the pressure in pipes, γ_α is the fluid gravity of phase α, Z is the depth of the reservoir, and s represent the distance along the pipe connecting junctions "l" and "j".
The second term in Eq. (1) is formulated from the steady state transfer equation used in many previous models

$$E_{\alpha l} = V_l T_{\alpha m}\left(p_{\alpha ml} - p_{\alpha pl}\right) \tag{3}$$

where $T_{\alpha m}$ is the phase α transmissibility of matrix and $p_{\alpha ml}$ is matrix pressure of the block "l". $T_{\alpha m}$ can be calculated by

$$T_{\alpha m} = \beta\left(\frac{K_m k_{r\alpha m}}{\mu_\alpha B_\alpha}\right)\sigma \tag{4}$$

where σ is the shape factor that represents the geometry of the matrix elements. Substituting (2) and (3) into (1), we obtain the flow equation in pipe network for phase α

$$\begin{aligned}&\sum_{j=1}^{M_l} -\frac{\beta A_{l,j} K_{pl.j} k_{r\alpha p}}{\mu_\alpha B_\alpha}\left(\frac{\partial p_{\alpha p}}{\partial s} - \gamma_\alpha \frac{\partial Z}{\partial s}\right) + V_l T_{\alpha m}\left(p_{\alpha ml} - p_{\alpha pl}\right)\\ &+ N_{\alpha l} = \frac{V_l}{5.615}\frac{\partial}{\partial t}\left(\frac{\phi_p S_{\alpha p}}{B_{\alpha p}}\right)\end{aligned} \tag{5}$$

Here, we assumed that the fluids for each phase from matrix and different pipes at junction "l" are completely mixed before they leave. Equation of phase α for matrix can be expressed as

$$V_l T_{\alpha m}\left(p_{\alpha ml} - p_{\alpha pl}\right) = \frac{V_l}{5.615}\frac{\partial}{\partial t}\left(\frac{\phi_m S_{\alpha m}}{B_\alpha}\right) \tag{6}$$

Equations (5) and (6) constitute the governing equations for the model proposed in this work. Combining with capillary pressure and saturation equations, the above conceptual model can be solved for pressures $p_{\alpha p}$, $p_{\alpha m}$ and saturations $S_{\alpha p}$, $S_{\alpha m}$.

The flow equations (5) and (6) are much simpler than traditional dual-porosity/permeability models. While the equations in (5) and (6) involve only first order derivatives, traditional models have to use second order derivatives of pressures. The other simplification of the model is the elimination of the requirement to define transmissibility at the block boundary. In Eq. (5), the permeability is defined directly along the pipe network. As we mentioned before, the most interesting advantage of the new model is its flexibility to arrange the pipes along the direction of the dominant fractures. This will help capture the oil and water movements without using small block sizes around large fractures.

Fracture Mapping

We continued our work on establishing correlations between well log patterns and well productivity. Table 2 shows a listing of individual wells with a summary of their cumulative fluid production. This allows inclusion of productive fractures even if they produced water from the onset of production. Substantial differences observed are attributed to the fracture density around the wells. In general, it is noted that well bores that intersect more formation containing lithologies prone to fracture development are potentially the better producers.

Table 2- Cumulative Production and Initial Rates			
Lease	Well Name	GROSS, B	Cum oil, B
3242	7-1	4349	2217
3242	10	19886	260
3120	15-1	31448	10631
3120	15-2	86360	54660
3120	4	460724	49009
3120	11	803614	565272
3242	19	877044	247617
3242	5	877614	376173
3242	8-4	946823	471580
3242	2	1008348	942198
3120	3	1127360	1104986
3242	4	1176664	728979
3242	10-1	1514417	308247
3120	6-2	1661054	1283010
3120	10	1726276	922771
3120	3-1	1794244	411353
3242	17	1963643	1149085
3120	14	2505013	718186
3242	13	2603481	599441
3120	8	2607746	2050460
3120	7-3	2855915	1470069
3242	16	3568874	1015924
3242	14	3958206	1914159
3242	11	4115560	2495519
3242	9	4685249	3395757
3242	15	5555647	3265600
3120	12	5828412	2811553
3120	16	5890974	3138080
3242	12	6205454	3033036
3120	13	6474534	2827087
3120	9-1	8193237	4666149
3242	18	15360704	9275300

A number of difficulties arose when the correlation between these IWPP (Intervals with Production Potential) and the actual productivity of the wells were examined. For some wells, there was a substantial history of workover changes in the completed intervals. The changes in the well completion, resulting from adding new intervals or abandonment of wet intervals, affect cumulative productivity. For these wells, the initial completion was not descriptive of the well's entire history. The wells with very limited production histories were also eliminated from the correlation studies.

Our correlation and pattern recognition work shows that some of the IWPP's were overlooked and some intervals with no productivity were perforated along with wet intervals (see Fig 2a). The initial WOR response identified the wells with initially wet perforated intervals.

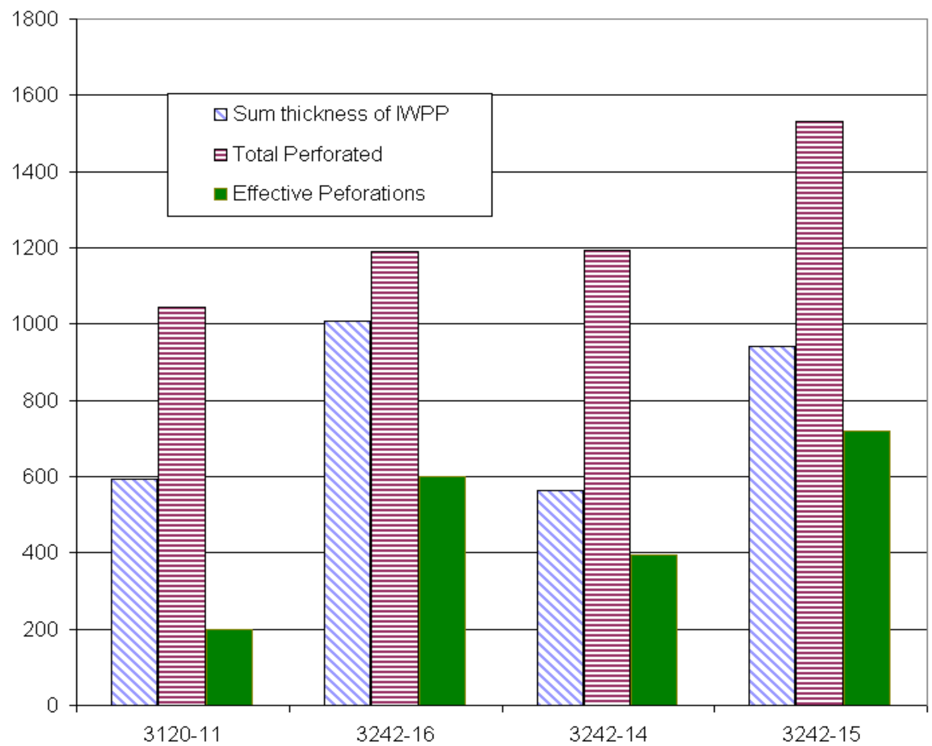

Fig. 2a – Bar chart representing IWPP, perforated intervals and over perforation.

The expectation is that the wells with frequent occurrences of IWPP will be better producers. The fraction of total interval consisting of IWPP was also examined against the cumulative gross production (see Figure 3).

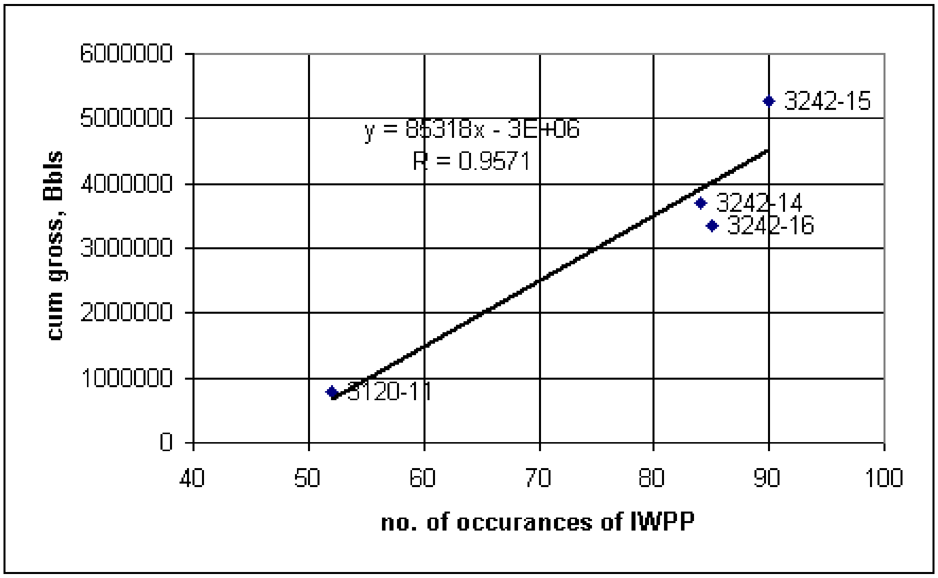

Fig 3 – Correlation between cumulative gross production and number of IWPP.

The points that are lie below the trend line are indicative of under perforation. The type of analysis is diagnostic for inclusion of untapped intervals. If we use cumulative oil production rather than gross production, the trend is not as perfect as that seen for the gross production. This is because several wells have initially wet completion intervals.

Permeability Estimation From Production Data

Applying the type curve approach discussed in the previous quarterly report, we analyzed the production data for the South Ellwood field. Using this technique, most South Ellwood wells yielded time ratios in the range 1.5-2.9.

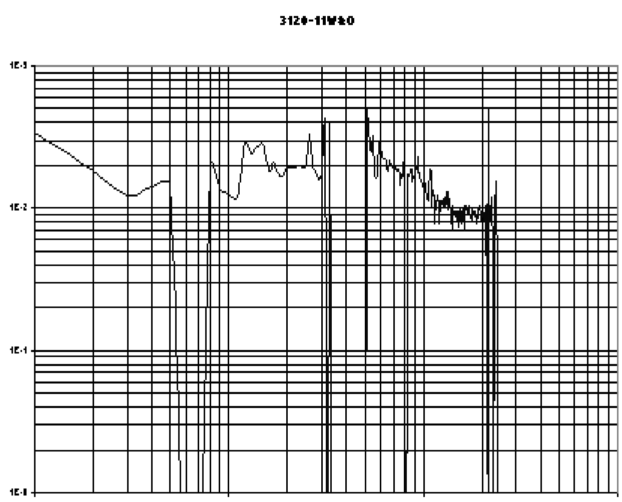

Fig.4 Decline characteristics for 3120-11

Using this value in the type curve for dual fracture systems (fig 5) yields a value for lambda in the order of 0.0003; a range not supported by the actual permeability characteristics of the matrix rocks in the Monterey reservoirs.

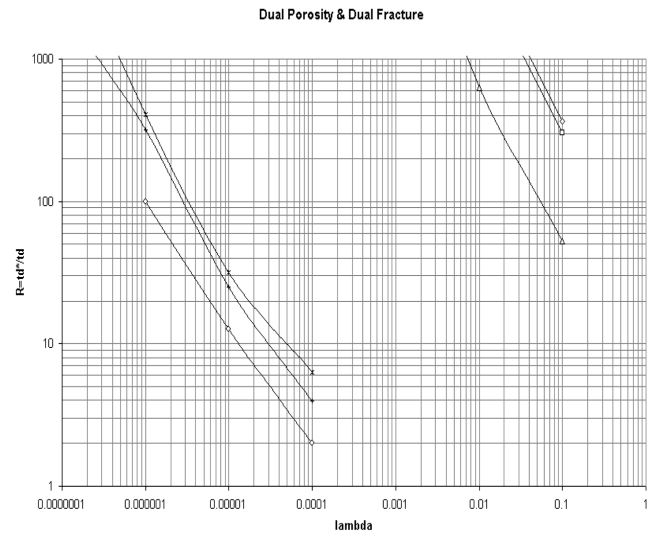

Fig.5 Dual Porosity & Dual Fracture,
Ratio of t_d^*/t_d vs. λ

Using early time rate-time performance data, representative values of permeability thickness are calculated for different wells and plotted on a bubble map for South Ellwood in Fig. 6.

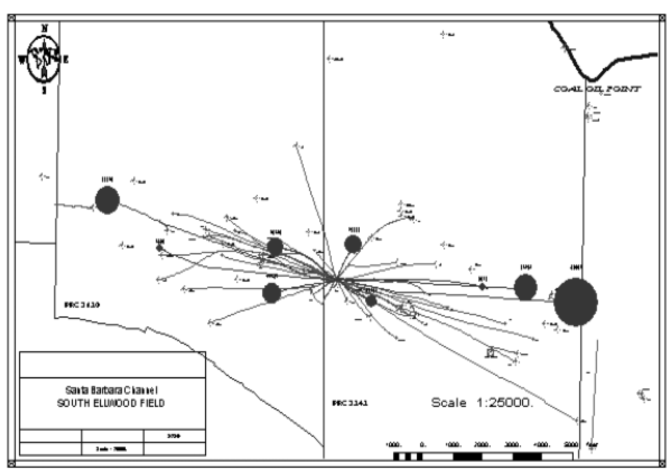

Fig. 6 Kh bubble map of various South Ellwood wells

The larger the bubble on the bubble map indicates a larger value of kh. This map demonstrates that adjacent wells can have distinct values of kh due to the heterogeneities found in a naturally fractured reservoir. The map indicates an areal variation exists in the permeability trend.

Basic Reservoir Engineering: and Fracture Orientation

We continued our effort in organizing the available data necessary for simulation studies. Correlations such as the one shown in Fig. 7 are helpful in identification of fracture directions.

The projected length of perforated sections of well traces on a specified axis are used to relate cumulative produced oil and local orientation of fractures.Those wells that all have completed zones in the same geographical location (SE, SW, etc, with respect to platform Holly as the origin of the coordinate system) follow a straight line trend on plots of cumulative oil versus perforated projected lengths.

Figure 7 for wells in the SE quadrant, shows a good correlation between cumulative production and perforated interval projected on a N-S axis. The biggest oil producer 3242-18 has the minimum projected length.

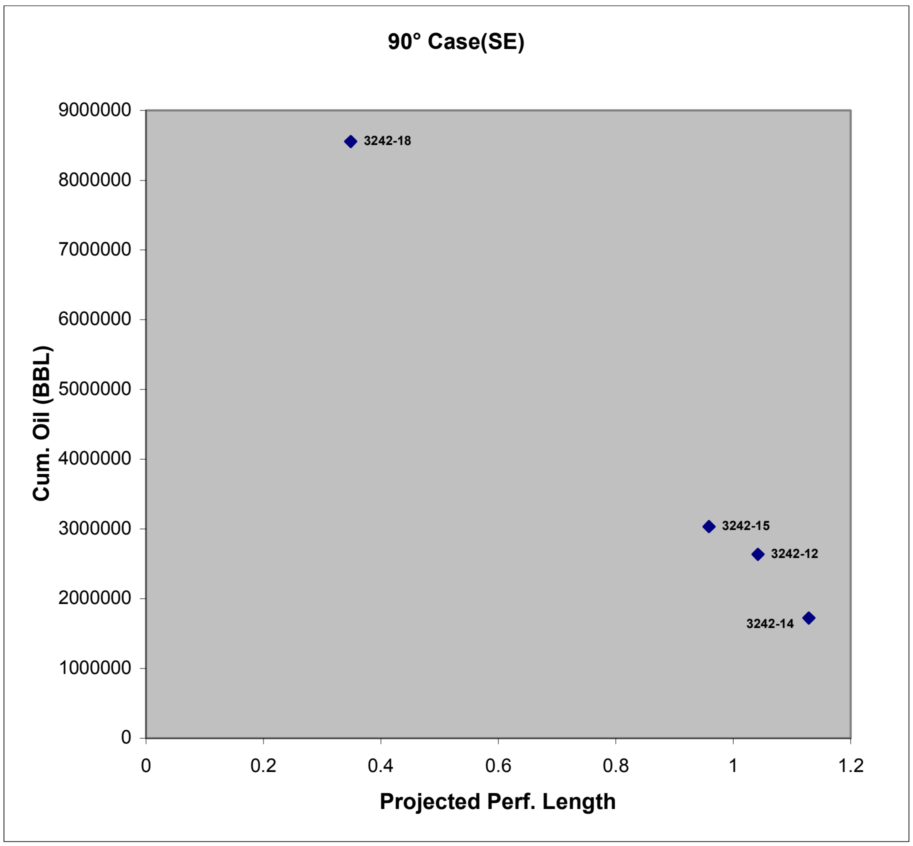

Figure 7: Cumulative oil versus projected perforation length on an arbitrary 90° axis for wells located in the quadrant SE of Holly

Task IV-Stimulation

None

Task V- Project Management

Project review meetings were held on a monthly basis in Santa Barbara. Progress reports from various individuals were reviewed. Individuals working on the project during this quarter included:

Database:
Katie Boerger (USC), Ursula Wiley (USC), Kim Halbert (Venoco), Tim Rathman (Venoco), Chris Knight (Venoco), I. Ershaghi (USC)

Reservoir Studies:
I. Ershaghi (USC), Lang Zhang (USC), A. Zahedi (USC), Ursula Wiley (USC), Juan Anguiano (USC), Steve Horner (Venoco)

Geological Modeling
Mike Wracher (Venoco), Karen Christensen (Venoco)

Geophysical Modeling
Karen Christensen (Venoco)

Project Management:
Karen Christensen (Venoco) and I. Ershaghi (USC)

Task VI--Tech Transfer

Two SPE papers were presented at the Western Regional meeting of the Society of Petroleum Engineers, March 25-30, 2001.
1-Mapping of Permeability Structure in a Naturally Fractured Reservoir Using Field Performance Data SPE 68833 Juan A. Anguiano, U. of Southern California; Iraj Ershaghi, U. of Southern California; Karen I. Christensen, Venoco
2-A New Diagnostic Method for Prediction of Producibility and Reserves of Wells Producing From the Monterey Formation Using Well-Log Data, SPE 68834; Ursula M. Wylie and Iraj Ershaghi, University of Southern California, and Karen Christensen, Venoco Inc.

Conclusions

The most significant event during the Third Quarter was that a new generation of production logging tools were run in five South Ellwood wells. The DEFT and GHOST tools identified zones for water shut-off in three wells. Workovers have been scheduled for these wells in 2002.